INDIANA UTILITY REGULATORY COMMISSION

ENERGY REPORT TO THE REGULATORY FLEXIBILITY COMMITTEE OF THE INDIANA GENERAL ASSEMBLY

AUGUST 2001

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Chapter 1 Purpose and Scope of the Report

This report is intended to satisfy the requirements of I.C. 8-1-2.5-9(b). The report outlines the status of the Indiana electric utility industry. The report reviews the activities of the electric industry in Indiana and provides an update of facts and developments since the Indiana Utility Regulatory Commission's 2000 Energy Report.[1] It also examines competition issues as they affect Indiana utilities.

[1] Energy Report, Indiana Utility Regulatory Commission, September 2000.

Chapter 2 Executive Summary

Electricity is something that many people take for granted. Today, electricity is a necessity, driving our economy and improving our quality of life. Further, as technology advances, the "quality" of electricity has become increasingly important. Sensitive electronic equipment in our homes and businesses require reliable electricity to function properly.

Five major investor owned electric companies, 79 municipally owned, and 43 distribution co-ops supply the electric needs of Hoosiers. Meeting the demand for electricity is getting more complicated, not only for the utilities that supply the electricity, but also for state regulators.

The need for new generation coupled with efforts to meet federal mandates to reduce emissions from power plants are impacting the price that we pay for electricity. Generating facilities owned and operated by Indiana utilities usually produce enough electricity to meet the demands of the Hoosier state.

The permitting process to build new generating plants in Indiana is not as long or as costly as in other states. Since 1999 the IURC has approved 7703 MW of new generating capacity, of which 1885 is operational.

This new generating capacity and the fact that over 90% of the electric power generated in Indiana is fueled by coal, makes it, in the Commission's opinion, unlikely that Hoosiers will see the same kind of power woes as consumers have in California.

The Commission is monitoring the progress of President Bush's proposed Energy Plan. The plan includes: giving government the authority to take property through eminent domain for power lines, easing of regulatory barriers, including clean air rules, to make power plants more efficient, funding for conservation efforts and the development of alternative energy sources.

Mergers are viewed with caution by federal and state regulatory agencies because the merged entity may be able to exercise increased market power resulting in noncompetitive prices, lack of product innovation, and a decrease in the range and quality of service to the consumer. Mergers can also threaten state commerce by reducing job levels or draining employees from one state to another. Some mergers, however, result in substantial benefits to the shareholders, customers and employees of the merged companies. All proposed mergers or acquisitions should be objectively analyzed to identify the potential negative and positive outcomes. Traditional merger evaluation criteria are based on the need to review mergers of companies operating in a competitive industry. The energy industry, however, has a natural tendency for developing a monopoly market making it particularly critical that mergers among energy utilities undergo a thorough evaluation before final approval.

Today, mergers of both electric and gas utilities frequently produce comparatively small savings from reduced administrative costs and other economies of size (scale). Often merger savings are offset by the inefficiencies associated with the operation of a much larger organization. As a result, the customer may experience little or no reduction in the cost of electricity or natural gas and decreased customer choice and service.

Mergers or acquisitions of Indiana electric utilities can have several effects. First, the parent company may opt to reduce the workforce of the Indiana utility, which can result in reduced service quality and reliability. Second, if the parent company owns subsidiaries that operate in other states, the Indiana company's customers can be affected by policies put into place in the other states. For example, if other states enact customer choice programs, the parent company may need to create new interconnection and operating agreements for its subsidiaries. The need for new agreements also points to the need for additional safeguards for state regulatory agencies in the areas of access to books and records, codes of conduct and affiliate rules. Finally, differences between states allowing retail customer choices and those that retain traditional utility regulation may have the inadvertent detrimental effect of reducing the economies of scale and scope of large multi-state companies in the operational areas of generation dispatching, and planning for transmission, new generation, and environmental equipment.

A merger can mean more than just a name change. A proposed merger should be carefully reviewed to determine the potential impact on the companies' workforce and customers.

Given the importance of electricity on our economy and quality of life, it would be beneficial to the interests of the State of Indiana, its citizens, and its electric consumers to have a meaningful review of utility mergers.

Chapter 3 Indiana's Electric Industry

This chapter is a review of the electricity industry in Indiana. First, the different types of utility companies, including merchant plants are described and then a closer look is taken at the developments in the formation of regional transmission organizations (RTOs).

Categories of Utilities

There are three types of ownership in the electric utilities --government (federal and municipal), cooperative and investor-owned. The overall goal for these utilities is to provide reliable electric service at reasonable cost to their customers. Distinct corporate structures, however, result in different methods employed to meet this goal and government policies do not affect each type of utility in the same manner.

Investor-Owned Utilities

The investor-owned utility (IOU) is the most significant in terms of generation and in number of customers served. Five major investor-owned utilities operate within the state:

- Indianapolis Power & Light (IPL), a wholly-owned subsidiary of AES Corporation;
- Indiana Michigan Power (I&M), wholly owned by American Electric Power (AEP);
- Northern Indiana Public Service (NIPSCO), a NiSource company;
- PSI Energy, a wholly-owned subsidiary of Cinergy Corporation; and,
- Southern Indiana Gas & Electric Company (SIGECO), a subsidiary of Vectren Energy Delivery of Indiana.

Investor-owned utilities are for-profit enterprises funded by debt and equity and, in Indiana, are still vertically integrated, meaning they own generation, transmission and distribution facilities. Table 1 presents generation and sales information for Indiana's five IOUs. The "Sales for Resale" illustrates that IOUs are typically able to generate enough power for their own requirements and produce power for sale in the wholesale market.

Table 1: Investor-Owned Utility Statistics – 2000

UTILITY	CAPACITY (MW)	TOTAL SALES (GWH)	SALES FOR RESALE (GWH)	RESIDENTIAL SALES (GWH)	COMMERCIAL SALES (GWH)	INDUSTRIAL SALES (GWH)
PSI	5,968	68,072	42,096	7,701	6,725	11,483
I&M	4,443	32,777	14,551	5,225	4,694	8,220
NIPSCO	3,392	17,493	1,547	2,953	3,376	9,495
IPL	2,968	16,421	2,314	4,614	1,990	7,432
SIGECO	1,236	7,525	2,296	1,381	1,336	2,492

Source: 2000 FERC Form 1

Municipal Utilities

There are 79 municipally owned electric utilities in Indiana. As of July 2001, twenty-five remain under IURC jurisdiction for rate regulation. Municipals are organized as nonprofit local government agencies and pay no taxes or dividends, although revenue can be turned over to the general city fund in the form of payment in lieu of taxes. Municipals raise capital through the issuance of tax-free bonds. Many municipals in the state are members of the Indiana Municipal Power Agency (IMPA). IMPA was created by a group of municipalities in 1980 to jointly finance and operate generation and transmission facilities and purchase power. IMPA is a political subdivision of the state under Indiana Code 8-1-2.2 and is not subject to state or federal income taxes.

IMPA owns generating facilities and has member-dedicated generation. It also holds ownership interest in two units, Gibson 5 (co-owned with PSI and Wabash Valley Power Association) and Trimble County 1 (co-owned with Louisville Gas and Electric and the Illinois Municipal Electric Agency). It meets the rest of its members' needs through purchased power.

Cooperatives

Another type of nonprofit electric utility is the cooperative. Forty-three distribution co-ops exist in Indiana. As of July 2001, four co-ops remain under Commission jurisdiction for rate regulation. Co-ops were formed as a result of the Rural Electrification Act of 1936 to bring electric service to rural areas.

Although co-ops were originally created to distribute power, since the 1960s over 50 generating and transmission (G&T) cooperatives have been formed nationally to supply power to distribution co-ops. Within Indiana, there are two Generation and Transmission co-ops: Hoosier Energy (HE) and Wabash Valley Power Association (WVPA). These co-ops serve as coordinators of bulk power supplies and transmission services for their members, as IMPA does for municipals.

Table 2 illustrates the proportion of power purchases to generation for IMPA, Hoosier Energy and Wabash Valley Power Association. The statistics for individual municipal and distribution co-op utilities are shown in Appendix A.

Table 2: IMPA/G&T Cooperative Statistics – 2000

UTILITY	CAPACITY (MW)	GENERATION (GWH)	PURCHASES (GWH)	SALES (GWH)
Hoosier Energy	1,266	9,116	786	9,150
IMPA	555	N/A	N/A	4,592
Wabash Valley	156	1,120	6,173	6,937

Source: 2000 Annual Reports.
The sum of Generation and purchases does not equal sales because of "Losses".

Withdrawal from IURC Jurisdiction

Under Indiana Code 8-1-13-18.5 municipal and cooperative utilities can withdraw from the jurisdiction of the IURC. To do this the utility must first obtain the approval of the members. This is done through a referendum that allows the members to vote whether they want the utility removed from commission jurisdiction. The withdrawal becomes effective 30 days after member approval. The utility must send verified certification of the vote to the commission not more than 5 days after the date of the vote. Once the utility withdraws from commission jurisdiction the commission continues to exercise jurisdiction over the utility with respect to electric service area assignment and certificates of public convenience and necessity.

Recently, a number of municipal and cooperative utilities have opted to withdraw from commission jurisdiction. The utilities commonly cite legal and other fees associated with commission regulation as a reason for withdrawal. The utilities also claim that because the customers and owners of municipal and cooperative utilities are one in the same, commission regulation is unnecessary. The utilities inherently have an incentive to provide adequate, reliable low-cost service to their customers.

Sales and Revenue Information

Table 3 is a comparison of average electric utility revenue per kWh by state for 2000 and shows that Indiana is still a low-cost state, mainly due to its coal reserves and its relatively small investment in expensive nuclear power. States shown in bold have not restructured their electric utility industry at this point in time. Appendix A provides more detailed information on sales, revenue and market share for Indiana utilities.

Table 3: Average Revenue per kWh by State (ranked from highest to lowest)

STATE	1998	1998	1999	1999	2000 (EST)	2000 (EST)*
	Residential	Average	Residential	Average	Residential	Average
Hawaii	**13.82**	**11.56**	**14.30**	**11.97**	**16.38**	**14.04**
New Hampshire	13.92	11.93	13.84	11.75	13.56	11.60
New York	13.66	10.71	13.32	10.40	14.08	11.19
Vermont	**11.61**	**9.83**	**12.17**	**10.28**	**12.13**	**10.22**
Rhode Island	10.91	9.58	10.13	9.02	11.52	10.20
Alaska	**11.50**	**9.97**	**11.16**	**9.78**	**11.42**	**9.98**
Maine	13.02	[illegible]	13.07	9.77	12.76	9.88
Connecticut	[illegible]	[illegible]	11.46	9.96	10.85	9.52
Massachusetts	10.60	[illegible]	10.09	9.16	10.82	9.50
New Jersey	11.39	10.17	11.40	9.99	10.81	9.08
California	10.60	9.03	10.71	9.34	10.58	8.53
District of Columbia	**8.00**	**7.41**	**8.00**	**7.45**	**8.03**	**7.52**
Arizona	8.68	7.33	8.53	7.23	8.43	7.18

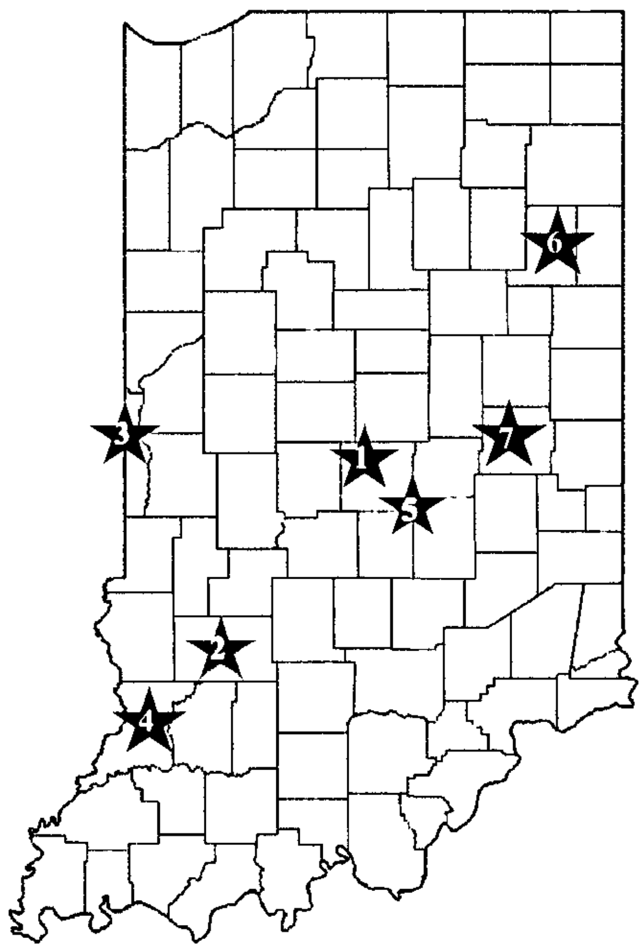
STATE	1998 Residential	1998 Average	1999 Residential	1999 Average	2000 (EST) Residential	2000 (EST)* Average
Michigan	8.67	7.09	8.73	7.14	8.51	7.11
Florida	**7.89**	**7.01**	**7.73**	**6.85**	**7.76**	**6.91**
Delaware	9.13	6.88	9.17	7.12	9.13	6.81
Maryland	8.44	6.99	8.39	7.04	7.97	6.75
Louisiana	**7.07**	**5.78**	**7.12**	**5.81**	**7.91**	**6.60**
Pennsylvania	9.93	7.86	9.19	7.67	9.07	6.59
Illinois	9.85	7.46	8.83	6.98	8.84	6.58
New Mexico	8.85	6.78	8.62	6.58	8.30	6.58
North Carolina	**8.01**	**6.45**	**7.99**	**6.44**	**8.02**	**6.51**
Ohio	8.70	6.38	8.68	6.40	8.56	6.51
Texas	7.65	6.07	7.55	6.04	7.90	6.46
South Dakota	**7.27**	**6.26**	**7.42**	**6.35**	**7.36**	**6.32**
Kansas	**7.65**	**6.28**	**7.64**	**6.22**	**7.65**	**6.26**
Georgia	7.67	6.40	7.56	6.24	7.76	6.24
Nevada	7.00	5.76	7.13	5.93	7.27	6.12
Missouri	**7.08**	**6.08**	**7.12**	**6.07**	**7.06**	**6.05**
Colorado	**7.45**	**5.95**	**7.38**	**5.95**	**7.37**	**6.00**
Oklahoma	6.57	5.43	6.60	5.37	7.15	5.95
Virginia	7.51	5.88	7.48	5.86	7.55	5.95
Mississippi	**7.03**	**5.98**	**6.75**	**5.65**	**7.03**	**5.93**
Iowa	**8.38**	**6.04**	**8.35**	**5.93**	**8.07**	**5.85**
Minnesota	**7.33**	**5.71**	**7.41**	**5.83**	**7.40**	**5.81**
Arkansas	7.51	5.78	7.43	5.68	7.48	5.79
Wisconsin	**7.17**	**5.44**	**7.31**	**5.53**	**7.54**	**5.69**
Tennessee	**6.32**	**5.62**	**6.34**	**5.63**	**6.33**	**5.62**
Alabama	**6.94**	**5.56**	**7.03**	**5.54**	**7.02**	**5.60**
North Dakota	**6.49**	**5.70**	**6.50**	**5.49**	**6.51**	**5.50**
South Carolina	**7.50**	**5.53**	**7.55**	**5.57**	**7.43**	**5.49**
Nebraska	**6.46**	**5.30**	**6.52**	**5.31**	**6.48**	**5.27**
Indiana	**7.01**	**5.34**	**6.96**	**5.29**	**6.80**	**5.13**
West Virginia	**6.29**	**5.07**	**6.27**	**5.09**	**6.32**	**5.11**
Montana	6.50	4.80	6.78	5.01	6.35	5.03
Utah	6.84	5.16	6.27	4.86	6.28	4.82
Oregon	5.82	4.90	5.75	4.87	5.91	4.78
Washington	5.03	4.03	5.10	4.10	5.15	4.48
Wyoming	6.28	4.31	6.34	4.30	6.58	4.38
Idaho	5.28	4.02	5.26	3.98	5.39	4.19
Kentucky	**5.61**	**4.16**	**5.58**	**4.17**	**5.33**	**4.12**
U.S. Average		6.74		6.66		6.69

Sources: Energy Information Administration: EIA-861, "Annual Electric Utility Report," and EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions."

Merchant Plants

Currently, there are seven merchant power plants operating in Indiana. Six of the facilities provide electricity to the wholesale market and one provides electricity solely to Indianapolis Power & Light. The DPL Generating Station and CinCap Station are the only new additions since summer 2000. Figure 1 identifies the merchant plants currently operating in Indiana.

Figure 1: Merchant Plants Operating in Indiana



1 IP&L Georgetown Station (80 MW) All output from the plant is transported on lines owned by IP&L to be used by IP&L customers. The facility began operation in May 2000. (Cause No. 41337)

2 Worthington Generation (180 MW) Williams Company purchased this facility from AES Corp. The facility's four combustion turbines were operational in June 2000. (Cause No. 41361)

3 Duke Vermillion (640 MW) The facility's eight turbines were operational in June 2000. (Cause No. 41388)

4 Wheatland Generating Facility (500 MW) Allegheny purchased this facility from Enron in late 2000. The facility's four turbines were operational in June 2000. (Cause No. 41411)

5 DTE Georgetown Station (160 MW) This plant is located on land owned by IP&L. Two turbines were operational in June 2000. (Cause No. 41566)

6 DPL Generating Station (200 MW) This plant currently has four turbines, which became operational in June 2001; another four turbines are due to become operational in Summer 2002. (Cause No. 41685)

7 CinCap Station (135 MW) This facility plans to have three turbines operational by the end of the summer. Only one is operational as of August 7, 2001. (Cause No. 41569)

Regional Transmission Organizations

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued Order 2000 to encourage all transmission owners to voluntarily join regional transmission organizations. It defined an RTO as "an entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within a region." The FERC established the following four minimum characteristics an RTO must satisfy:

- Independence - The RTO must be independent of market participants;
- Scope and Regional Configuration - The RTO must serve an appropriate region to permit the RTO to effectively perform its required functions and to support efficient non-discriminatory markets;
- Operational Authority - The RTO must have operational authority for all transmission facilities under its control; and
- Short-term Reliability - The RTO must have exclusive authority for maintaining the short-term reliability of the grid that it operates.

The order required all public utilities that own, operate or control interstate transmission facilities to file with the FERC by October 15, 2000, a proposal for an RTO to be operational by December 15, 2001. Alternatively, utilities could file a description of efforts to participate in an RTO, obstacles to participation and any plans to work toward RTO participation. A public utility that was a member of an existing transmission entity approved by FERC under principles established in Order No. 888, had to make a filing no later than January 15, 2001. This filing had to explain how the existing transmission entity complied with the minimum characteristics and functions established in Order No. 2000. Two RTOs are being formed in the Midwest region – The Midwest Independent

System Operator and the Alliance RTO. NIPSCO and I&M filed with the FERC to join the Alliance RTO. PSI Energy, IPL, SIGECO, IMPA, Hoosier and WVPA filed with the FERC to join the Midwest ISO.

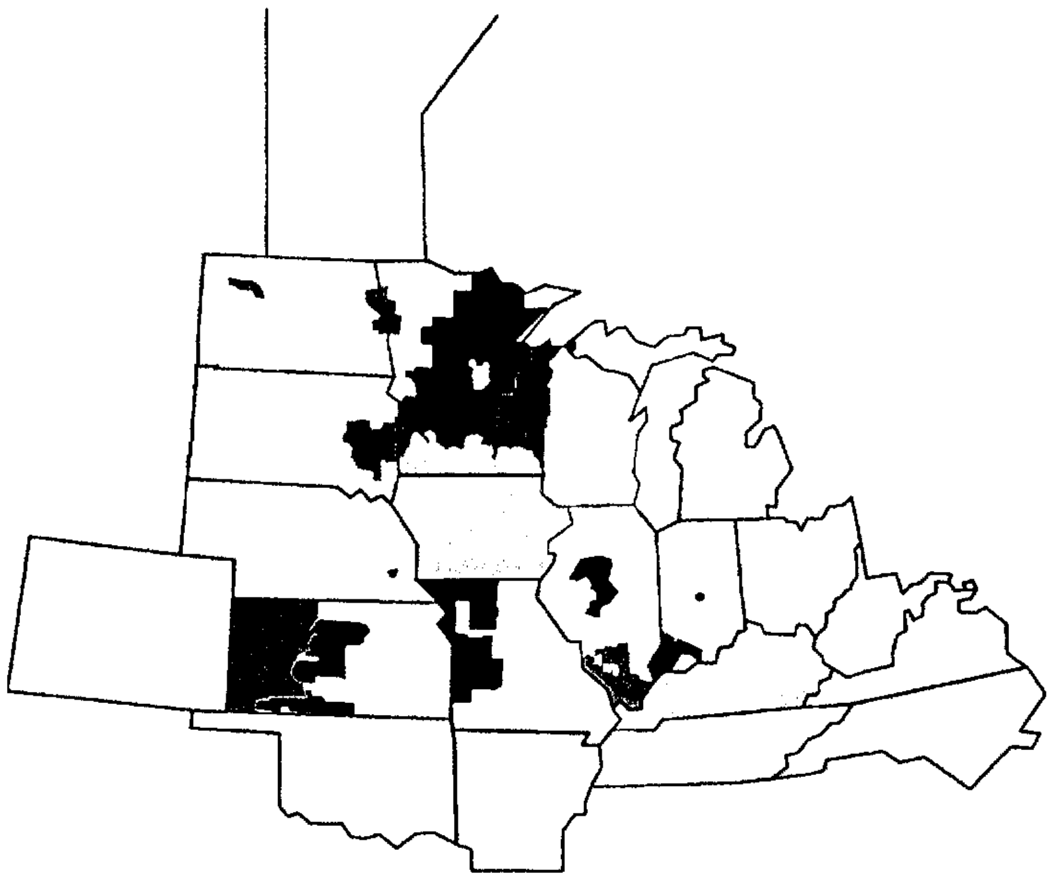
On June 25, 2001, the Indiana utilities associated with the MISO filed a petition with the IURC to transfer the operational control of their transmission assets to their associated RTO. On June 29, 2001, the Indiana utilities associated with the Alliance RTO also filed a petition with the IURC to transfer the operational control of their transmission assets to their associated RTO.[2] The respective Cause Nos., 42027 and 42032, were consolidated and a prehearing conference was held July 30, 2001. The parties have requested an aggressive schedule, which would allow the IURC to issue an order by December 10, 2001 so that the RTOs can become operational by December 15, 2001.

Midwest Independent System Operator (MISO)

The Midwest ISO was founded on February 12, 1996, and was specifically configured to comply with the FERC's concept of an independent organization that would ensure the smooth regional flow of electricity in a competitive wholesale marketplace. The MISO manages nearly 42,000 miles of transmission lines covering more than 235,000 square miles from North Dakota to Kentucky. The individual members are listed in Appendix B and Figure 2 shows the geographic scope of the organization. The MISO headquarters and control center are in Carmel, Indiana, where market trials will start in August 2001 and it is expected to be fully operational by December 15, 2001.

[2] Cause No. 42027 is the petition by PSI Energy, IPL, Vectren Energy Delivery of Indiana (formerly SIGECO), Hoosier and WVPA to transfer control of transmission assets to the MISO. Cause No. 42032 is the petition by I&M and NIPSCO to transfer control of transmission assets to the Alliance.

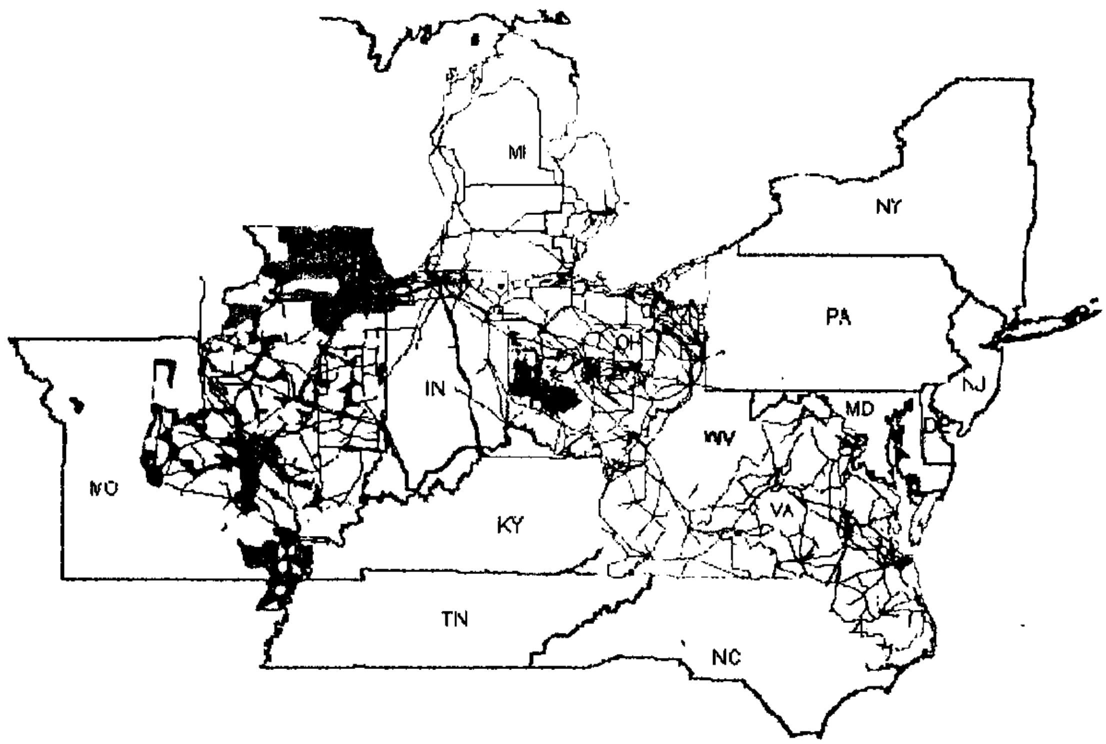
Figure 2: Midwest ISO Service Area



The Alliance Regional Transmission Organization

On July 12, 2001, the FERC issued a conditional approval of the Alliance RTO. This was in reply to the May 15th Alliance Supplemental Filing in which Alliance was to demonstrate that the proposed RTO satisfies the minimum functions and characteristics for an RTO under Order No. 2000. This approval brings the Alliance one step closer to being ready for operation by December 15, 2001. The Alliance RTO owns over 57,000 miles of transmission lines and serves a population of approximately 41 million people in 11 states. Figure 3 show the geographic scope of the Alliance RTO, which includes a combined service area of over 190,000 square miles. It will operate transmission systems that are connected to more than 105,000 MW of load with generation capacity exceeding 112,000 MW. The companies associated with the Alliance RTO are listed in Appendix B.

Figure 3: Alliance RTO Service Area



Chapter 4 Indiana's Electric Industry – Current Issues

Mergers and Acquisitions

Mergers are viewed with caution by federal and state regulatory agencies because the merged entity may be able to exercise increased market power resulting in noncompetitive prices, lack of product innovation, and a decrease in the range and quality of service to the consumer. Mergers can also threaten state commerce by reducing job levels or draining employees from one state to another. Some mergers, however, result in substantial benefits to the shareholders, customers and employees of the merged companies. All proposed mergers or acquisitions should be objectively analyzed to identify the potential negative and positive outcomes. Traditional merger evaluation criteria are based on the need to review mergers of companies operating in a competitive industry. The energy industry, however, has a natural tendency for developing a monopoly market making it particularly critical that mergers among energy utilities undergo a thorough evaluation before final approval. It is difficult to apply traditional merger evaluation criteria when analyzing mergers among energy utility companies because some utility functions remain regulated monopolies while others are in the initial stages of transition to more competitive markets.

Prior to 1996, electric utility merger applications argued that customers would realize substantial savings due to the coordination of generating unit dispatch and other operations. In April 1996, the Federal Energy Regulatory Commission issued Order 888, which requires transmission-owning utilities to allow other power suppliers equal access to their transmission systems on non-discriminatory terms. As a result, many of the previously touted coordination benefits can now be achieved without a merger.

Today, mergers of both electric and gas utilities frequently produce comparatively small savings from reduced administrative costs and other economies of size (scale). Often merger savings are offset by the inefficiencies associated with the operation of a much larger organization. As a result, the customer may experience little or no reduction in the cost of electricity or natural gas and decreased customer choice and service.

Mergers or acquisitions of Indiana electric utilities can have several effects. First, the parent company may opt to reduce the workforce of the Indiana utility, which can result in reduced service quality and reliability. Second, if the parent company owns subsidiaries that operate in other states, the Indiana company's customers can be affected by policies put into place in the other states. For example, if other stat[illegible] choice programs, the parent company may need to create new int[illegible] and operating agreements for its subsidiaries. The need for new agreements also points to the need for additional safeguards for state regulatory agencies in the areas of access to books and records, codes of conduct and affiliate rules. Finally, differences between states allowing retail customer choices and those that retain traditional utility regulation may have the inadvertent detrimental effect of reducing the economies of scale and scope of large multi-state companies in the operational areas of generation dispatching, and planning for transmission, new generation, and environmental equipment.

AES Acquisition of IPALCO

On March 17, 2001, the AES Corporation (AES) completed its acquisition of IPALCO Enterprises, Inc., whose subsidiary Indianapolis Power & Light serves 433,000 customers in central Indiana. AES is a global power company comprised of competitive generation, distribution and retail supply businesses. The transaction has been approved by the Federal Energy Regulatory Commission and the Securities and Exchange Commission (SEC). At the time of the merger's announcement, AES indicated its intention to restructure or sell its ownership interests in CILCORP, an Illinois power company, within a specified period of time in order to continue as an exempt holding company under the Public Utility Holding Company Act of 1935 (PUHCA). An exempt holding company is exempt from certain portions of PUHCA. To obtain this status, the holding company typically operates a utility in only one state. If a company is not exempt, it becomes a registered holding company, and is subject to the full range of PUHCA regulations.

On January 16, 2001, the IURC and the OUCC intervened in the case before FERC of AES' acquisition of IPALCO (Docket No. EC01-25-000). The parties (IURC, OUCC, AES, IPALCO, and IPL) reached a settlement agreement that resolved various issues in the case. The stipulation was filed at FERC on February 5, 2001. It contained the following provisions regarding customer satisfaction and reliability of service:

> Industry Parties [The AES Corporation, IPALCO Enterprises, Inc., and IPL] commit to make every reasonable effort to continue to achieve, after AES acquires IPALCO, levels of service reliability and customer satisfaction within IPL's service territory not less than those that preceded the acquisition. IPL will make no material change in its call center operations that would reasonably be expected to result in its customer service deteriorating below present levels without prior consultation with the IURC and OUCC.[3]

In January 2001, IPALCO announced an offer of buyouts to some of its 1900 employees, of which 400 (a limit imposed by IPALCO) accepted. A further round of buyouts numbering 250 began in June 2001 and will be finished by August 2002.

On July 25, 2001, the IURC initiated an investigation into any and all matters relating to IPL's statutory obligation to provide reasonable service (Cause No. 41962).

AEP Merger Savings Flow Back to Indiana Customers

In July of 2001, Indiana Michigan Power Company filed with the IURC to begin to reduce its customers' bills due to the merger of AEP with the Central and South West Corporation. The amounts of the reductions were agreed upon in a settlement agreement in Cause No. 41210, approved by the IURC on April 26, 1999. Because of a court appeal

[3] Indiana Utility Regulatory Commission Notice of Withdrawal of Intervention and Protest, The AES Corporation/IPALCO Enterprises, Inc., FERC Docket No. EC01-25-000, page 7.

(Citizens Action Coalition v. Indiana Michigan Power Co., Court of Appeals, 93A02-9906-EX-453, Appeal from Cause No. 41210, IURC decision affirmed by the Court on October 24, 2000), the merger savings reductions have been delayed about one year, and in the next year customers will receive amounts from year 1, with interest, and year 2 of the merger. The merger savings reductions will continue for eight years, and will total approximately $67 million over eight years. In the first year, the annual merger savings per average residential customer is $8.96; per average commercial customer is $110.44; and per average industrial customer is $10,812.79. For each rate class, the annual merger savings per average customer is 1.23%.

Southern Indiana Gas and Electric Company Merger and Name Change

On April 1, 2001, Southern Indiana Gas and Electric Company, as well as Indiana Gas Company, both began operating under the name Vectren Energy Delivery of Indiana. This name change, which was approved by the IURC, came about from the merger of the parent companies of Indiana Gas and SIGECO in 2000.

Although the SEC approved the Vectren merger in March 2000, and it was essentially completed on March 31, 2000, there is a pending case involving the merger at the IURC. On June 17, 1999, SIGECO filed with the IURC for submission of information and review by the Commission of the holding company merger, and for deferred accounting of certain merger related costs (Cause No. 41465). On July 23, 2001, a Stipulation and Settlement Agreement was filed in the case. Representatives of the OUCC, Indiana Gas Company, SIGECO, and the Vectren Corporation signed the agreement. The parties agreed that the utilities will withdraw their request for accounting authority to defer and amortize the costs-to-achieve the merger. The agreement also contains provisions for affiliate guidelines, cost allocation guidelines, merger cost and benefits, quality of service, budget billing, and Low-Income Home Energy Assistance program contributions. The approval of the stipulation and settlement agreement is pending before the IURC.

How Restructuring Is Affecting a Non-Restructuring State

Cinergy Operating Agreement

On March 14, 2001, the IURC initiated an investigation into the proposed termination of the operating agreement between PSI Energy, Inc. (PSI), Cincinnati Gas & Electric Company (CG&E), and Cinergy Services (Cause No. 41954).

The original operating agreement was entered into by the subsidiaries as a result of the 1994 merger between CG&E and PSI Resources. The operating agreement was part of a negotiated settlement between PSI and various citizens' groups, which was approved by the IURC in Cause No. 39837. The negotiated settlement was one of a series of agreements required by FERC before it approved the 1994 merger. The operating agreement was established to provide for the coordinated planning and operation of the two regulated entities' generation and transmission systems, and addressed issues such as joint dispatch of the generating systems, joint capacity and environmental compliance planning, trading of environmental emissions allowances and operation of the joint transmission system.

On October 23, 2000, Cinergy filed a notice of termination of the operating agreement with the Federal Energy Regulatory Commission (FERC) (Docket No. ER01-200-001). Cinergy's reason for the termination filing is that, with the introduction of retail competition in the state of Ohio, "PSI and CG&E no longer will share the common characteristics that formed the basis for the Operating Agreement."[4]

The IURC order initiating the investigation stated, "in light of the fact that the Operating Agreement affects PSI's operation and the Operating Agreement was an integral part of the [merger settlement] agreement approved by the Commission, the proposed termination of that Operating Agreement warrants investigation by the Commission."

In October 2000, settlement negotiations with Cinergy, an IURC staff negotiating team, and other parties began in the FERC proceeding. The parties filed a settlement with the FERC on May 9, 2001, resolving termination issues and certain compensation and damage issues. The settlement, which is pending FERC approval, extends the termination of the existing operating agreement until a new successor agreement has been allowed to become effective by the FERC. The settlement also provides that the parties will engage in negotiations concerning such a successor agreement and that Cinergy must obtain IURC approval for certain agreements and must obtain approval from the FERC for other agreements under section 205 of the Federal Power Act.

Some of the issues brought up in prefiled testimony from the IURC investigation include: dispatching protocols (Cinergy has proposed to transfer power between PSI and CG&E generating units with the payments based on market prices), generation planning (Joint planning may be difficult in light of the spin-off of CG&E generating units), environmental issues (Joint planning with CG&E and PSI generating units may still be valuable), transmission issues (Cinergy must, under FERC rules, operate and plan the facilities as a single system), the service agreement (changes in the structure and operations of Cinergy might necessitate a revision to the service agreement), codes of conduct and affiliate rules (what types of safeguards are necessary to prevent the "market price" energy transfers from manipulation by Cinergy, undue preference being given to Cinergy affiliates, and to allow for appropriate information flow to regulatory bodies.)

The negotiating parties filed a Settlement Agreement in the IURC investigation proceeding on August 10, 2001. On August 16, 2001, a hearing was held regarding the terms of the settlement. Cinergy will file a proposed order in the proceeding by August 24, 2001.

[4]Cinergy Services Inc., Cincinnati Gas & Electric Co and PSI Energy Inc., initial FERC filing of a notice of termination of certain Operating Agreement, dated 3/2/94 by CG&E, PSI & Services designated as Cinergy Operating Companies, 10/26/2000, Docket No. ER01-200-001, page 2.

AEP Corporate Restructuring Plan

On July 24, 2001, American Electric Power Company (AEP) filed documents with FERC to implement a planned restructuring of the corporation's regulated and unregulated holdings (FERC Docket No. ER01-2668).[5] AEP is a large power holding company whose subsidiaries operate in eleven states. The Indiana subsidiary of AEP is Indiana Michigan Power Company (I&M), which operates in northern Indiana. Due to some of the states (Ohio and Texas) in which AEP operates introducing retail electric choice programs, while other states remain regulated, AEP has found it necessary to modify and create new agreements among its subsidiaries as it operates in the new environment. Laws in Ohio and Texas have mandated legal separation of AEP's generating companies in those states. The decision about corporate separation is pending in Virginia, while West Virginia has also enacted restructuring legislation, but has postponed implementation.

Some of the goals of AEP in seeking approval for these new agreements are to maintain the benefits of integrated operations for customers; continue to provide customers with a reliable power supply; provide power at a comparable cost structure; modify the existing agreements to remove companies in the deregulated states of Ohio and Texas; to separate regulated and unregulated merchant functions, and to maintain actual fuel cost-based pricing for retail fuel clauses.

In its FERC filing, AEP has proposed a restated and amended AEP-East Interconnection Agreement among the three remaining AEP-East operating companies—Appalachian Power Company, Indiana Michigan Power Company, and Kentucky Power Company.[6] According to AEP, this new agreement will permit those companies to continue the mutually beneficial coordination of their operations without the participation of the Ohio AEP operating companies. The primary change in the agreement is the withdrawal of the Ohio AEP operating companies as Members and, therefore, as participants in the energy exchange arrangements. AEP has also proposed to eliminate the provisions for capacity equalization payments; to price energy purchases from other Members at the midpoint between the Seller's Incremental Cost and the Purchaser's Decremental Cost; and to change the formula for allocating the proceeds of off-system sales. AEP has stated that the overall effect on the payments and receipts for Indiana Michigan Power Company under the new agreement will be small for the 2002-2004 period.

AEP also intends to terminate the Interim Allowance Agreement among the AEP-East operating companies. This agreement has provided a mechanism for allocating among those companies the benefits and costs of Clean Air Act emissions allowances. AEP proposes that the allocation of emissions allowances will now be covered in the amended AEP-East Interconnection Agreement.

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[5] The initial AEP filings at FERC are available at: http://www.aep.com/news/corpsep.htm.

[6] The current AEP system is comprised of two parts following the merger of AEP with Central and South West Corporation: "AEP-East" consists of the pre-merger AEP operating companies and "AEP-West" consists of the pre-merger CSW operating companies.

AEP has requested that FERC grant approval in order for the agreements to become effective on January 1, 2002. AEP has requested that FERC appoint a settlement judge, sponsor settlement proceedings, and after the close of the period provided for comments and interventions, move directly to a settlement conference. AEP believes that the settlement conference will narrow and define the differences among the stakeholders that remain for FERC resolution, or possibly lead to resolution of the entire proceeding through settlement.

On August 1, 2001, the IURC initiated an investigation (Cause No. 42045) into the proposed termination of the 1951 Operating Agreement between American Electric Power, Inc. and Indiana Michigan Power Company.

RTO Developments

When Dynegy merged with Illinova Corporation it had several reasons to withdraw its Illinois Power Company from the Midwest Independent System Operator (MISO) and join the Alliance RTO. Specific reasons included that the rates for transmission services for Illinois Power would be lower as part of the Alliance RTO and that the Alliance RTO covered more states that have introduced retail competition. This initiated a wave of conditional withdrawals, including Ameren Corporation and Commonwealth Edison Company, should FERC permit Illinois Power to leave. In response to these filings the MISO stated that the departure of the Illinois companies[7] would create a large hole in the middle of the Midwest ISO leaving it with a technically challenging scope and configuration. MISO asserted that open-ended RTO member withdrawal will only frustrate the interregional goals set out in Order 2000 and had the potential of creating more seams issues[8] and making coordination among RTOs more difficult. Several interveners emphasized that three of the four RTO characteristics were in jeopardy of being severely compromised if the departures were permitted. More specifically, the Midwest ISO stated the following concerns:

- The Midwest ISO would not be able to raise additional capital funding for its start-up independent of its members;
- An adequate scope and regional configuration was at risk because the potential departures would carve out highly interconnected facilities in the MISO; and
- The exclusive authority to maintain short-term reliability is diluted because the Midwest ISO will not have the authority to redispatch generation connected with the transmission facilities owned by Illinois Power, ComEd and Ameren.

On January 24, 2001, FERC ordered the parties to participate in expedited settlement discussions, starting in early February. After 30 days of extensive negotiations, a formal Stipulation and Agreement (Settlement Agreement) was filed with FERC on March 21,

[7] Illinois Power Company, Ameren Corporation and Commonwealth Edison Company.
[8] Some examples of seams issues between RTOs include congestion management protocols, the reciprocal elimination of pancake transmission charges, coordination of commercial practices, security coordination, market monitoring, regional planning, transmission capability calculations, curtailment procedures, and coordinated outage planning.

2001, directing how the MISO and Alliance RTO were to work together to create a seamless market for transmission throughout the Midwest.

RTO uncertainties and settlement

The Settlement Agreement permitted the Illinois Companies to join the Alliance RTO and included several important provisions that provided adequate mitigation for both RTOs to remain compliant with FERC Order 2000. The FERC accepted the Settlement Agreement on May 8, 2001, including the following key terms:

- The creation of a single "super-regional" rate for transmission service within a region that combines the area of the MISO and the Alliance; stretching from the Dakotas to the Mid-Atlantic region.
- An agreement for negotiations among the MISO, the Alliance and PJM for a joint "through-and-out" rate.
- The approval of the withdrawals of Commonwealth Edison, Ameren and Illinois Power from the MISO, in exchange for paying a combined exit fee of $60 million to the MISO.
- The Inter-RTO Cooperation Agreement (IRCA) in which the RTOs agreed to coordinate their efforts to develop seamless transmission service in the Midwest.

Inter-RTO Cooperation Agreement (IRCA) and seams issues

In Order No. 2000, the FERC identified that the coordination of activities among regions is a significant element in maintaining a reliable bulk transmission system and for the development of competitive markets. It required an RTO to develop mechanisms to coordinate its activities with other regions whether or not an RTO yet existed in these other regions. The FERC directed RTOs to work closely with other regions to address interregional problems and problems at the seams between the RTOs. The FERC did not mandate that RTOs have uniform practices but did state that reliability and market interface practices must be compatible among the RTOs.

As part of the Settlement, the MISO and the Alliance signed an Inter-RTO Cooperation Agreement (IRCA) that includes the development of protocols and procedures for coordinated transmission planning, coordinated security operations, a cohesive congestion management approach, independent market monitoring, one-stop shopping facilitation, compatible real-time balancing markets, generation interconnection standards and compatible business practices. The Settlement Agreement is viewed by some stakeholders as providing a vehicle for the further development of one large RTO encompassing the Midwest region. While several stakeholders would have rather seen the Midwest ISO and Alliance Companies merge, the IRCA allows the Transco and the ISO business models to coexist.

The IRCA is designed to facilitate cooperation between the RTOs and the coordination of transmission services in a manner that provides transmission users seamless access to transmission services markets throughout the regions served by the Alliance RTO and the Midwest ISO. The agreement itself and the related procedures and protocols, however, are basically meaningless pieces of paper unless these documents are ultimately transformed into workable methods and procedures that will fulfill transmission customers' needs when the respective RTOs become fully operational in December 2001.

The maps of the two RTOs clearly show that the eastern portion of the Midwest ISO is not interconnected with the western portion of the Midwest ISO. However, despite the difficult seams between the Midwest ISO and the Alliance, the combined Super Region encompasses a contiguous geographic area, and a highly interconnected portion of the grid, across much of the Midwest and reaching all the way to the East Coast.

Future developments

As deregulation unfolds and wholesale competition increases, the need for transmission independence and an RTO structure became increasingly apparent to FERC. In a move that pushes the nation farther down the path of restructuring wholesale power markets, FERC ordered on July 12, 2001, that three independent system operators[9] covering 12 Northeastern states[10] to form one regional transmission group, and ordered four utilities in the Southeast to form another separate system. The groups would set rules for the regional market systems and facilitate easier transmission of power across state lines. A similar move has been proposed for the western states, including California. The FERC decided that to successfully address seams issues and establish efficient markets, it is necessary to eventually form a total of four RTOs in the whole of the United States. The effect of this order on the developments in the Midwest is still unknown but will certainly encourage the parties to work together to sort out their issues.

Merchant Plants

Merchant power plants are considered different from traditional utilities in that the electricity they generate is sold in the wholesale market, not to retail customers. The company that constructs the merchant plant assumes the costs of construction and operation with the expectation that the costs will be recovered through electricity sales to the wholesale market. In contrast, traditionally regulated utilities recover the construction and operating costs from their retail customers through the ratemaking process. To be as competitive as possible, merchant plant developers choose their site location to be as close to both a supply of natural gas, for fuel, and an electricity transmission line, for access to the wholesale power market. Keeping the costs of fuel supply and transmission access low helps the plants to be more competitive in the wholesale market.

Merchant plant electricity is typically generated by either a single or combined cycle combustion turbine fueled by natural gas. A single cycle combustion turbine simply uses the gas to power its turbine (like a jet engine) and produce electricity. In the case of a combined cycle turbine, the heat from the turbine is captured and used to create additional electricity. All but two of the proposed merchant plants in Indiana plan to be

[9] New England Power Pool (NEPOOL), New York ISO (NYISO) and Pennsylvania Jersey Massachusetts (PJM)

[10] New York, Pennsylvania, Massachusetts, Delaware, District of Columbia, Maryland, New Jersey, Virginia, Connecticut, New Hampshire, Maine and Vermont

either gas-powered single or combined cycle combustion turbines. Two coal-burning merchant plants were proposed in February 2001, and are currently under consideration at the Commission; and a coal-burning cogeneration plant had been proposed, but its petition was dismissed at the petitioner's request in June 2000.

For the past ten years, Indiana's electric companies have been opting not to invest in new generating plants due to concern over changes in the industry and the fear of stranded costs. Recently, IP&L, SIGECO, and PSI have filed petitions with the IURC to construct new generation. Instead of building, many utilities have been purchasing additional power on the open wholesale markets from merchant plants. While this can be cost-effective in the short-term, it can expose both the utility and its customers to the volatility of the wholesale market. Although the merchant plants locating in Indiana are not necessarily going to sell their power to companies in Indiana, the increase in generation capacity in Indiana and surrounding states would be expected to improve capacity margins and regional reliability.

Up to this point, all the merchant plant petitioners have been defined as public utilities under I.C. 8-1-2-1. However, Commission orders specified that the merchant plant utilities would not exercise any of the rights, powers, or privileges of public utilities and would not sell electricity directly to retail customers or recover any of their costs through a rate base. Based on these specifications, the Commission, to date, has been declining to exercise most of its jurisdictional powers over the petitioners and the construction and operation of their proposed merchant plants. Thus far, proposed merchant plants in Indiana and in other states have been designated as exempt wholesale generators (EWG), as defined by the Public Utility Regulatory Policies Act (PURPA), and are subject to more federal, and fewer state regulations.

Increasingly, merchant plant petitioners have been called on to answer difficult questions surrounding their operations. Opponents have noted that while merchant facilities are under no obligation to provide their capacity to Indiana, they do make use of Indiana's water, release emissions in Indiana's air and sometimes locate near unwilling neighbors. The potential benefits and risks involved with limiting merchant plant development in Indiana were hotly debated during the 2001 session of the General Assembly. In the end, the status quo was maintained and the still on-going debate was relegated to the cases before the Commission. With each new petition begins a new discussion at the Commission on the merits of continued development.

Three Indiana investor-owned utilities, IPL, PSI, and SIGECO, have built or are planning to build peaking power generation units, similar in structure to typical merchant plants. The difference between the two is that while merchant plants sell their electricity on the wholesale market, peaking plants are used by a utility for additional generation during periods of increased demand. Therefore, although these facilities are not merchant plants, for completeness, we have included the plants in this section.

Table 4 compares the proposed (not approved) merchant plant capacity across the country. Indiana and its surrounding states are in bold face print.

Table 4: Proposed Merchant Plant Capacity by State Ranked by Total Capacity

STATE	PROPOSED CAPACITY (MW)	STATE	PROPOSED CAPACITY (MW)
Texas	35567	Connecticut	4140
California	21883	Oregon	3754
Ohio	**19490**	South Carolina	3720
Illinois	**19213**	Montana	3400
Arizona	18490	Tennessee	3196
Florida	16355	Missouri	2651
Michigan	**14850**	Maine	2124
Indiana	**12910**	Maryland	2085
Pennsylvania	12596	Colorado	1938
New York	11681	North Carolina	1920
Virginia	9749	New Mexico	1818
Mississippi	9697	Wyoming	1630
Massachusetts	9161	Idaho	1550
Alabama	9158	New Hampshire	1430
Georgia	8891	Vermont	1225
Louisiana	8329	Iowa	1200
Nevada	7892	North Dakota	1000
Kentucky	**7241**	Rhode Island	807
Washington	6927	Delaware	588
Arkansas	6047	Minnesota	534
West Virginia	5957	Utah	160
Wisconsin	5410	Kansas	110
New Jersey	4886	Alaska	3

Source: Electric Power Supply Association (EPSA) as of 7/31/01.

Table 5 details the merchant plant petitions either currently before the commission or approved and under construction. Plants currently under construction are shown in bold type.

Table 5: Proposals Currently Before the Commission

Proposed Facility	Proposed Capacity	Location	Estimated Completion Date	Cause Number
Cogentrix	**800 MW**	**Lawrence Co.**	**Summer 2002**	**41566**
PSEG Lawrenceburg	**1150 MW**	**Dearborn Co.**	**Summer 2002**	**41757**
Sugar Creek Energy	**533 MW**	**Vigo Co.**	**June 1, 2002**	**41753**
Duke Energy Knox	**640 MW**	**Knox Co.**	**June 1, 2002**	**41803**
Duke Energy Vigo	**620 MW**	**Vigo Co**	**June, 2002**	**41804**
Tenaska	1800 MW	Pike Co.	Second Quarter of 2003	41823
Putnam Energy	**500 MW**	**Putnam Co.**	**Summer 2002**	**41856**
PSEG Morristown	**340 MW**	**Shelby Co.**	**Summer 2003 or 2003**	**41867**
Hammond Energy	540 MW	Lake Co.	Undetermined	41900
Mt. Vernon Energy	540 or 800 MW	Posey Co.	Undetermined	41901
EnviroPower Pike	550 MW	Pike Co.	Spring 2005	41931
EnviroPower Sullivan	550 MW	Sullivan Co.	Summer 2004	41932
Acadia Bay	630 MW	St. Joseph Co.	Phase I in 2002	41966
SIGECO	80 MW	Posey Co.	Undetermined	41907
PSI	300 MW	Hamilton Co.	Undetermined	41924
IP&L	185 MW	Marion Co.	Undetermined	42033
Whiting Clean Energy	**500 MW**	**Lake Co.**	**February 2002**	**41530**

Issues Not Directly Affected by Industry Restructuring

EPA Actions

On October 27, 1998, the U.S. Environmental Protection Agency (EPA) published a final federal rule (commonly called the NOX SIP Call; SIP is an acronym for State Implementation Plan) that requires each of the twenty-two states in the eastern United States, including Indiana, to reduce emissions of nitrogen oxides significantly (an approximate 85% reduction from 1990 levels). Nitrogen oxides (NOX) are a precursor to ozone formation, and the federal rule is intended to reduce the transport of ozone and ozone pollutants that occurs in this multi-state region. The NOX SIP Call affects several types of large industrial boilers, but the bulk of reductions fall on the electric utility industry.

Numerous parties (many of the 22 states and groups of utilities) challenged EPA's rule the District of Columbia U.S. Court of Appeals. In March 2000, the Court upheld the NOX SIP Call Rule. A subsequent request for rehearing was denied. The original compliance deadline was May 1, 2003, but due to the court delays, the deadline is now May 31, 2004. EPA directed each state to file its final SIP to comply with this rule by October 28, 2000. Due to statutory requirements, it took the Indiana Department of

Environmental Management (IDEM) about one year to finalize the rule. IDEM finalized the rule on June 6, 2001

IDEM estimated that capital costs for Indiana for the NOX rule are around $1.4 billion, total ozone seasons costs at around $265 million, and the overall cost effectiveness at $2,230 per ton of NOX removed. IDEM also estimated that these additional costs will translate into electric rate increases of 6 to 7% or $0.0033 per kilowatt hour for Indiana customers.

Two electric utilities have filed cases involving NOX control costs before the IURC. PSI Energy, Inc. received approval of the use of certain qualified pollution control property on February 14, 2001 (Cause No. 41744). In this case, PSI estimated the total cost of its NOX Reduction Compliance Plan to be $428,339,800. Southern Indiana Gas & Electric Company (SIGECO) has filed a petition for approval of the use of qualified pollution control (Cause No. 41864). SIGECO estimated its construction costs to be $198,302,000 to meet the NOX SIP Call requirements.

A NOX reduction effort similar to the SIP Call is also moving forward, with the difference that the deadline for compliance is May 2003. Under Section 126 of the Clean Air Act, the EPA granted petitions filed by states claiming that other states' pollution has contributed to their local ozone problem. The petitions granted apply to facilities in the eastern half of Indiana owned and operated by AEP, PSI Energy, IMPA, the City of Richmond, and the Indiana-Kentucky Electric Corp. The pollution targeted is NOX emissions, and the remedy is the same as the limits in the NOX SIP Call. Some sectors had hoped that the EPA would move back the deadline to May 31, 2004 to coincide with the new SIP Call date, but so far that has not happened.

Since the pollution control equipment to control NOX must be installed and operational by either May of 2003 or 2004, utilities now have four or six outage windows, respectively, in which to get the work done. An outage window occurs in the spring and fall of each year when demand for electricity is lower. Utilities perform various maintenance activities during these windows. The NOX pollution control equipment installations will require generating units to be offline for a longer time period. This additional outage time creates a risk to the reliability of power; specifically to generation adequacy, which means simply having enough power to meet consumer needs. One mitigating factor to this reliability risk is the addition of new merchant plant generation across the region. Although the NOX regulation was delayed by litigation, it is important to note that utilities have been working on their plans for some time, and some have already begun the construction and installation process in 2000 and the spring of 2001.

The EPA, through the Department of Justice, has filed a lawsuit against seven utilities (including AEP, Cinergy, and SIGECO) claiming that they "violated the Clean Air Act by making major modifications to many of their plants without installing the equipment required to control smog, acid rain and soot." Utilities consider the activities to be routine maintenance and repair, and are fighting the lawsuit in court. Possible remedies include fines and the installation of the most up-to-date pollution control equipment.

Cinergy announced that it had reached a tentative settlement of the lawsuit in December 2000, but to date the agreement has not been finalized.

IURC Investigation of Rates and Charges by NIPSCO

On January 27, 2000, the Citizens Action Coalition and a group of ratepayers filed a complaint in Cause No. 41651 alleging that the rates and charges of Northern Indiana Public Service Company were unreasonable and that NIPSCO had received earnings that exceed its allowable rate of return. On May 17, 2000, the Commission issued a docket entry in that cause indicating that based upon preliminary review of NIPSCO's 1999 annual report filed on April 17, 2000, the fact that the four year periodic review was scheduled in 2000 and that NIPSCO's recent fuel adjustment cost (FAC) filing suggest that the company may be over-earning, it intended to initiate an investigation into the reasonableness of NIPSCO's rates, docketed as Cause No. 41746. At that time the Commission stated its intention to consolidate the two causes into the 41746 proceeding.

Pursuant to I.C. 8-1-2-42.5 the Commission staff conducted the four-year periodic review of NIPSCO's earnings status. On January 24, 2001, the results of the review and the recommendation that a formal investigation into the reasonableness of NIPSCO's rates be initiated were made to the Commission by the staff. As a result, a formal investigation was initiated and all parties to the original complaint in Cause No. 41651 were notified of the proceeding.

On February 28, 2001, a prehearing conference was held to discuss proposed schedules regarding procedural matters. On March 21, 2001, the Commission issued an order setting out the procedural schedule for this cause. All parties, including NIPSCO, filed their prepared testimony and exhibits constituting their respective cases-in-chief on June 8, 2001. Rebuttal testimony was scheduled to be filed September 7, 2001, with an evidentiary hearing scheduled for October 2, 2001.

The March 21 order also separated the 41651 and 41746 causes. Due to the timing of the initiation of the respective causes, each had to be administered pursuant to the procedural rules in effect at that time, therefore the causes had to be re-separated. The results of both of these causes are still pending.

Chapter 5 Differences Between California and Indiana

The electricity situation in California has generated a substantial amount of attention. The events have caused many to reexamine both the idea of retail competition and energy policies for the nation. There were many factors that contributed to the situation in California. This section explains the many factors that led to the outcome in California, and contrasts that situation with the state of the electric industry in Indiana.

Demand

Fueled in part by the digital economy and migration of new residents into the state, demand in California has grown faster than in the Midwest. From 1995 to 1999, demand in California grew 2.23% annually while in the ECAR region (the nine east-central state region including Indiana) demand grew 1.25% annually.[11] Annual peak demand growth in Indiana from 1995 to 1999 was 1.86%, according to the State Utility Forecasting Group. In California peak demand increased 12% from 1996 to 1999, and demand increased by 5% in the first eight months of 2000. Furthermore, growth in California's neighboring states has been high, thus reducing the amount of power available to sell to California. Both utilities and regulators in California did not anticipate the growth in the state or the region.

Another factor driving demand higher was that with the rate cuts mandated by the restructuring law, and the fact that utilities were precluded from passing on price increases from the wholesale market, fixed retail prices did not send any price signal to consumers about the need for conservation.

With the constants of high growth rates and fixed retail electric rates moving California to a precarious demand and supply balance, extreme weather events that raised peak demand were enough to cause rolling blackouts. These events were triggered by historically cold temperatures in the winter and very high temperatures in the spring of 2001.

Supply

Until this summer, no large coal-fired, nuclear, or hydro power plants came online in California in over a decade. The permitting process for new generation is long and costly. The California Energy Commission (CEC) authorizes siting permits, using a two-stage review. On average, five projects approved by the CEC since 1995 have taken 505 days to approve. Only 672 MW of new supply (largely gas-fired) has been added since 1996. Another factor limiting supply is that price caps have reduced the incentive for generators to locate new plants in the state.

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[11] Some of this information is taken from the Ohio Electric Utility Institute (http://www.oeui.org/pages/choiceinfo.htm), the Public Utilities Commission of Ohio (http://www.puc.ohio.gov/Consumer/Electric/ohiovcalif.html), and the Energy Information Administration (http://www.eia.doe.gov/cneaf/electricity/st_profiles/toc.html).

The permitting process to build new generation in Indiana is not nearly as long or as costly as it is in California. Since 1999, the IURC has approved 5243 MW of new generating capacity, of which 1750 MW is currently operational. A significant amount of new generation is also occurring in neighboring states such as Ohio and Illinois.

Demand and Supply Balance

As a result of the above facts, the reserve margin in California is 4.6% while for the ECAR region it is 11.1%. According to the State Utility Forecasting Group, the reserve margin for Indiana was 21% for 2000, and is 19% in 2001.[12] As a result, California must depend upon out of state power transfers to meet its needs for much of the time, while Indiana rarely needs to import power to serve its needs. Indeed, the EIA classifies Indiana as an electricity exporter, while California is an importer.

Transmission

California imports about 25% of its power from out of state, but major bottlenecks in the transmission system limit the ability to move power. Transmission lines in California run primarily north and south, and the siting and installation of new lines is difficult. Overall, Indiana and the Midwest do not currently have significant transmission constraints.

Nature of the Market and Institutional Factors

During the last few years the California electric market was primarily short-term in nature. Utilities were forced to divest a large portion of their generation, and were blocked by regulators from entering into stable long-term contracts to buy power. Investor-owned utilities were required to participate in a Power Exchange, and thus rely on spot market purchases to meet their customers' electricity needs. When demand was low, spot prices were low, but when demand was high, prices rose—during some episodes, price increases of thousands of percentage points occurred. These soaring prices were the result of the increase in demand, dramatically higher natural gas prices, some generation plants offline for maintenance or repairs, and lower amounts of imports from other states. The skyrocketing wholesale prices combined with the frozen retail rates meant that the retail electric companies were forced to absorb the difference. As a result, Pacific Gas and Electric declared bankruptcy, and Southern California Edison has been near bankruptcy.

In Indiana, electric utilities own and operate their own generating units, and the amount of generation is usually enough to satisfy the needs of their customers. Utilities that need to satisfy their needs with power purchases have utilized a portfolio approach in which short, intermediate, and long-term purchases are made. Similarly, if a utility needs to make a purchase due to an unforeseen problem with its own generation, it does not have to buy power on the hourly spot market, but can utilize a wide variety of market instruments to meet its need for power.

[12] The SUFG includes merchant plant capacity in this calculation.

Fuel Source for Generation

California depends heavily upon natural gas, hydroelectric, and nuclear power for its electricity production. Hydroelectric capacity has been reduced in the last few years due to regional drought conditions. During the last year, the price of natural gas rose dramatically, and in some cases availability itself was scarce. As a result, the price of electricity produced by natural gas rose substantially.

Over 90% of electricity produced in Indiana comes from coal. Natural gas peaking units are used, but for a very small amount of hours during the year. Consequently, the price increases in natural gas last year had little effect upon electric prices and rates.

In light of all of the factors enumerated above, the chance of a California-style, systemic power crisis happening in Indiana is remote. That is not to say that problems cannot occur—particularly in the short-term due to weather conditions, equipment breakage or both—but recurrent power shortages, utilities on the brink of or declaring bankruptcy, or markedly higher retail electric rates do not appear to be even remote possibilities in Indiana.

Chapter 6 Federal Activities

Bush Administration's National Energy Policy

On May 16, 2001, The National Energy Policy Development Group (NEPDG) issued its National Energy Policy report. The group had been established by President Bush and was headed by Vice President Cheney with the mandate to develop a national energy policy.

The NEPDG identified three basic principles for the development of the policy. These principles are[13]:

- The Policy is a long-term, comprehensive strategy, recognizing that the energy crisis facing our nation has been years in the making, and will take years to resolve.
- The Policy will advance new, environmentally friendly technologies to increase energy supplies and encourage cleaner, more efficient energy use.
- The Policy seeks to raise the living standards of the American people, recognizing that to do so our country must fully integrate its energy, environmental, and economic policies.

Applying these principles, the NEPDG established five national goals and developed specific recommendations to meet them. Following is a brief description of each goal and the recommendations associated with it.

Modernize Conservation

In its report the NEPDG stated, "The best way to meet the goal of modernizing energy conservation is to increase energy efficiency by the continued research and development and subsequent application of these new technologies." Recommendations regarding the modernization of conservation include the following:

- Making funding available for the continued research and development of energy efficiency technologies by public-private partnerships in performance based programs;
- Increase consumer information about energy efficient goods and services by expanding the Energy Star program, strengthening Department of Energy's public education programs relating to energy efficiency, and expanding product energy efficiency labeling requirements; and,
- Improving the energy efficiency of appliances through new appliance efficiency standards.

Modernize Energy Infrastructure

The National Energy Policy report identified several factors that have contributed to reduced electric reliability nationwide. These factors included:

[13] "National Energy Policy, Report of the National Energy Policy Development Group, May 16, 2001, p. xi.

- Restructuring of the electric utility industry and the move to competition which, has led to significant changes in the operation of the bulk transmission system from the original design of the facilities;
- Regional shortages of generating capacity and transmission constraints;
- The voluntary compliance with reliability standards for the electric transmission system;
- Transmission line siting authority resting with state and local governments even though power sale transactions are increasingly interstate or even international in nature.

To improve reliability the report presented the following recommendations:

- Establish a self-regulatory organization, subject to FERC oversight, to enforce reliability standards.
- Examine the benefits of establishing a true, national transmission grid. Conjunctive legislation at the federal, state, and local levels would be developed to grant authority to obtain rights-of-way for electric transmission lines, similar to the authority that exists for natural gas pipelines.

Increase Energy Supplies

The report endorsed a policy that would promote the use of new technologies to be used by generators of electricity to insure a diversity of generating fuel and the protection of the environment. NEPGD made the following recommendations to meet this goal:

- Provide funding of research in clean coal technologies;
- Coordinate federal, state and local agencies to provide greater regulatory certainty to generators who generate electricity by using coal.
- Increase the environmentally safe expansion of the use of traditional fuels used for generating electricity, including nuclear fuel.

Accelerate the Protection and Improvement of the Environment

Recommendations regarding various forms of renewable energy include the following:

- Administrative and legislative reform of the hydropower licensing process, making the licensing process more clear and efficient while preserving environmental goals;
- Increased funding and support for the research and development of renewable energy technologies. Making use of bid bonuses from the leasing of the Alaska National Wildlife Refuge for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass;
- Expansion of the Section 29 tax credit to make it available for new landfill methane projects and would extend and expand tax credits for electricity produced using wind and biomass;
- Expand eligible biomass sources to include forest related sources, agricultural sources, and certain urban sources;
- Allow a credit for electricity produced from biomass co-fired with coal; and,
- Institute a new 15% tax credit for residential solar energy property, up to a maximum credit of $2,000.

Increase Our Nation's Energy Security

The report presented a policy that would increase the nation's energy security by reducing America's dependence on foreign energy sources. It also identified preparing for supply emergencies and assisting low-income Americans as necessary for increasing energy security. Specific recommendations included:

- Dedicate new funds to the Low Income Home Energy Assistance Program by funneling a portion of oil and gas royalties to LIHEAP;
- Double funding for the Department of Energy's Weatherization Program;
- Direct the Federal Emergency Management Administration to prepare for potential energy-related emergencies;
- Support a North American Energy Framework to expand and accelerate cross-border energy investment by streamlining and expediting permitting procedures.

Legislation and actions necessary to implement the proposed National Energy Policy are still in the development stage.

Federal Legislation

The driving force behind much of the energy legislation proposed in the 107th Congress was the desire for a comprehensive, national energy policy to be developed. Several bills taking a comprehensive approach to the reform of current legislation and in the proposal of new legislation have been proposed. The bills that currently appear to be the most likely to move this session are S. 388 and S. 389, *National Energy Security Act of 2001*, Murkowski (R-AK); and S. 597, *Comprehensive and Balanced Energy Policy Act of 2001*, Bingaman (D-NM). There were hearings on S. 388 and S. 597 as recently as July 26 and August 2, respectively.

Bingaman's legislation, S. 597, aims to establish a National Commission on Energy and Climate Change and an Interagency Working Group on Clean Energy Technology Transfers, along with establishing many other projects to encourage emerging energy technologies. His bill as it is currently written, also prescribes guidelines for renewable energy sources, distributed generation and hydroelectric facilities, and vehicular fuel efficiency.

The Murkowski bill, S. 388, mandates federal studies and reports to Congress regarding specific national energy needs and resources, as well as creates research and development programs. The bill also amends Public Utilities Regulatory Practices Act (PURPA) and repeals Public Utilities Holding Company Act (PUHCA), which would mean dramatic changes in the electricity industry. The bill's stated goal is to reduce the United States' dependence on foreign oil.

Table 6: Energy-Related Legislation Introduced in the 107th Congress

S. 172, *Electric Reliability Act*, Smith (R-OR)	S. 206, *Public Utility Holding Company Act of 2001*, Shelby (R-AL)
S. 388, S. 389, *National Energy Security Act of 2001*, Murkowski (R-AK)	S. 597, *Comprehensive and Balanced Energy Policy Act of 2001*, Bingaman (D-NM)
S. 972, *The Electric Power Industry Tax Modernization Act*, Murkowski (R-AK)	H.R. 264, (No short title), DeFazio (D-OR)
H.R. 954, *Home Generation Act*, Inslee (D-WA)	H.R. 1679, *Electricity Supply Assurance Act of 2001*, Graham (R-SC)
H.R. 1045, *Energy Self Sufficiency Act for the 21st Century*, Wilson (R-NM)	S. 352, *Energy Emergency Response Act of 2001*, Bingaman (D-NM)
H.R. 1101, *Public Utility Holding Company Act of 2001*, Pickering (R-MS)	H.R. 1874, (No Short Title), Hunter (R-CA)

Another bill, which is not as comprehensive as the others, but is likely to move this year is S. 352, proposed by Senator Bingaman (D-NM). This bill proposes to increase funding to the Low Income Home Energy Assistance Program, weatherization assistance and state energy conservation grants.

Chapter 7 Glossary

Affiliate: A company, partnership or other entity with a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas or electric energy or related services.

Aggregator: An entity that pools customers into a buying group for the purchase of a commodity good or service.

Alternative Regulatory Plan (ARP): In contrast to cost-of-service regulation, alternative regulatory plans are designed to allow the utility more flexibility in pricing energy to customers. ARPs may also contain provisions to streamline the regulatory approval process.

Ancillary Services: Services that must be provided in the generation and delivery of electricity. As identified by the FERC, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and economic dispatch of plants); contractual arrangements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

Broker: An agent for others in negotiating contracts, purchases or sales of electricity and associated services without owning any transmission or generation facilities. Unlike a marketer, a broker does not take title to the electricity being bought or sold.

Capacity: The size of a plant (not its output). Electric utilities measure size in kilowatts or megawatts and gas utilities measure size in cubic feet of delivery capability.

Convergence Mergers: In the context of energy, mergers between gas and electric utilities.

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders and benefits are in the form of products or services rather than profits.

Cost-of-Service: A term related to the current methods of regulating utilities (both gas and electric). A cost-of-service study analyzes a utility's average costs (also called embedded costs) of facilities and expenses in relationship to its revenues to determine rates (prices) for the customer. This is generally referred to as cost-of-service ratemaking or cost-of-service pricing.

Demand-Side Management (DSM): Conservation resource planning that considers factors affecting energy usage for each customer class; generally designed to reduce or shift load.

Distribution: The component of a gas or electric system that delivers gas or electricity from the transmission component of the system to the end-user. Usually the energy has been altered from a high pressure or voltage level at the transmission level to a level that is usable by the consumer. Distribution is also used to describe the facilities used in this process.

Generation: The process of producing electricity. Also refers to the assets used to produce electricity for transmission and distribution.

Gigawatt-Hour (GWh): One gigawatt of generation for one hour.

Green Power: Term used to describe electricity produced from environmentally friendly or renewable resources, such as solar or wind power; see "Renewable Energy."

Holding Company: A corporate structure where one company holds the stock (ownership) of one or more other companies but does not directly engage in the operation of any of its business.

Independent System Operator (ISO): An independent organization or institution that controls the transmission system in a particular region. The ISO would have no corporate relationship with the transmission-owning utilities, and therefore would be able to assure fair and comparable access to the transmission system for all users.

Kilowatt (kW): A basic unit of measurement; 1 kW = 1,000 watts.

Kilowatt-Hour (kWh): One kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Megawatt (MW): One thousand kilowatts or one million watts.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends; they raise capital through the issuance of tax-free bonds.

North American Electric Reliability Council (NERC): A nonprofit organization formed for the purpose of coordinating electric system operation and planning throughout North America, including Mexico and Canada.

Pancaking: Occurs when a seller attempts to transmit electricity through the control areas of several utilities and must pay a separate transmission charge to each utility.

Public Utility Holding Company Act of 1935 (PUHCA): A federal law that sought to correct abuses of utility holding companies. Holding companies largely confined to a single state or presumed to be susceptible to effective state regulation are "exempt" from federal regulation under PUHCA. Multi-state holding companies must "register" with the SEC and comply with federal regulation under PUHCA.

Public Utility Regulatory Polices Act of 1978 (PURPA): A federal law that requires utilities to buy electric power from private "qualifying facilities" at an avoided cost rate. The avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase the power itself. Utilities must further provide customers who choose to generate their own electricity a reasonably priced back-up supply of electricity.

Registered Holding Company: Any company that acquires more than 10 percent of the equity of a utility and as a consequence, must register with the Securities and Exchange Commission and is subject to all provisions of PUHCA.

Reliability: A term used in both the electric and gas industry to describe the utility's ability to provide uninterrupted service of gas or electricity. Reliability of service can be compromised at any level of service: generation or production, transmission or distribution.

Renewable Energy (Green Power): Naturally replenishable energy resources; includes geothermal, biomass, hydro-electric, solar, tidal action and wind as means of electricity generation.

Senate Enrolled Act 637: Codified as IC 8-1-2.5, this statute enables the IURC to consider alternative regulatory plans, among other things.

Service Territory: Under the current regulatory environment, an electric utility is granted a franchise to provide energy to a specified geographical territory, designated as a service territory.

Stranded Costs: Costs associated with assets that prove to be uneconomical in a competitive environment. Because these assets were previously approved by regulatory authorities and included in rates, utilities claim they should be able to fully recover these costs before the transition to customer choice is completed.

Transition Costs: Costs resulting from restructuring an industry from a regulatory environment to a competitive environment. Stranded costs are included in transition costs but may not be the only costs incurred.

Transmission: The process of transferring energy (either gas or electricity) from the production or generation source to the point of distribution. Also refers to the facilities used for this process.

Unbundling: The process of separating out the package of services offered by an electric or gas company and charging separate rates for each service that fairly represents the cost of providing the service. In the electric industry, these may include: transmission, generation, distribution services, metering, billing, maintenance. In the natural gas industry, in addition to transportation of gas, unbundling may include storage, gathering, balancing services and other items.

Vertically Integrated Utilities (companies): An arrangement whereby the same company owns most or all of the facilities necessary for producing, transporting and selling electricity (or gas). Traditionally, vertically integrated electric utilities have owned the generation, transmission and distribution facilities. In some cases, electric utilities have also owned coal mines and gas supplies to increase the level of vertical integration.

Chapter 8 Appendices

APPENDIX A: Sales, Revenues And Market Share For Electric Utilities

2000 Summary

MWH

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	21,875,510	18,121,297	39,121,946	366,313	79,485,066
Rural Electric Membership Corporations	3,956,935	434,776		6,351	4,398,062
Municipal Utilities	1,332,209	3,590,870		355,587	5,278,666
Totals	**27,164,654**	**22,146,943**	**39,121,946**	**728,251**	**89,161,794**

REVENUE (000s)

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	1,497,988	1,080,132	1,557,297	1,569	4,176,986
Rural Electric Membership Corporations	65,004	23,551		1,395	89,950
Municipal Utilities	80,017	169,093		31,581	280,691
Totals	**1,643,009**	**1,272,776**	**1,557,297**	**74,545**	**4,547,627**

RETAIL MARKET SHARE BY MWH

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	80.53%	81.82%	100%	50.30%	89.15%
Rural Electric Membership Corporations	14.57%	1.96%		0.87%	4.93%
Municipal Utilities	4.90%	16.21%		48.83%	5.92%

RETAIL MARKET SHARE BY REVENUES

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	91.17%	84.86%	100%	55.76%	91.85%
Rural Electric Membership Corporations	3.96%	1.85%		1.87%	1[illegible]
Municipal Utilities	4.87%	13.29%		42.37%	6.17%

Investor-Owned Electric Utilities – 2000 Data

MWH

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	5,224,988	4,694,355	8,220,375	86,583	18,226,301
Indianapolis Power & Light Company	4,614,421	1,989,649	7,432,115	71,378	14,107,563
Northern Indiana Public Service Company	2,953,275	3,375,873	9,494,928	121,870	15,945,946
PSI Energy, Inc.	7,701,426	6,725,373	11,482,556	67,250	25,976,605
Southern Indiana Gas & Electric Company	1,381,400	1,336,047	2,491,972	19,232	5,228,651
Totals	**21,875,510**	**18,121,297**	**39,121,946**	**366,313**	**79,485,066**

REVENUE (000s)

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	$ 340,484	$ 269,650	$ 334,622	$ 6,689	$ 951,445
Indianapolis Power & Light Company	285,000	130,482	337,725	10,250	763,457
Northern Indiana Public Service Company	291,078	282,256	413,790	13,806	1,000,930
PSI Energy, Inc.	488,610	324,149	388,526	8,732	1,210,017
Southern Indiana Gas & Electric Company	92,816	73,595	82,634	2,092	251,137
Totals	$ 1,497,988	$ 1,080,132	$ 1,557,297	$41,569	$4,176,986

AVERAGE RATE PER KWH

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	$0.07	$0.06	$0.04	$0.08	$0.05
Indianapolis Power & Light Company	$0.06	$0.07	$0.05	$0.14	$0.05
Northern Indiana Public Service Company	$0.10	$0.08	$0.04	$0.11	$0.06
PSI Energy, Inc.	$0.06	$0.05	$0.03	$0.13	$0.05
Southern Indiana Gas & Electric Company	$0.07	$0.06	$0.03	$0.11	$0.05

RETAIL MARKET SHARE

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	35.79%	28.34%	35.17%	0.70%	100%
Indianapolis Power & Light Company	37.33%	17.09%	44.24%	1.34%	100%
Northern Indiana Public Service Company	29.08%	28.20%	41.34%	1.38%	100%
PSI Energy, Inc.	40.38%	26.79%	32.11%	0.72%	100%
Southern Indiana Gas & Electric Company	36.96%	29.30%	32.90%	0.83%	100%

Rural Electric Membership Corporations – 2000 Data

MWH

Utility	Residential	Commercial & Industrial	Other	Total
Harrison County R.E.M.C.	280,971	162,368	363	443,702
Jackson County R.E.M.C.	3,357,367	66,878	4,464	3,428,709
Marshall County R.E.M.C.	63,994	14,811	690	79,495
Northeastern R.E.M.C.	254,603	190,719	834	446,156
Totals	3,956,935	434,776	6,351	4,398,062

REVENUE (000s)

Utility	Residential	Commercial & Industrial	Other	Total
Harrison County R.E.M.C.	$ 17,989	$ 7,814	$ 586	$ 26,389
Jackson County R.E.M.C.	24,028	4,108	511	28,647
Marshall County R.E.M.C.	5,431	1,058	153	6,642
Northeastern R.E.M.C.	17,556	10,571	145	28,272
Totals	$ 65,004	$ 23,551	$1,395	$ 89,950

AVERAGE REVENUE PER KWH

Utility	Residential	Commercial & Industrial	Other	Total
Harrison County R.E.M.C.	$ 0.06	$ 0.05	$ 1.61	$ 0.06
Jackson County R.E.M.C.	$ 0.01	$ 0.06	$ 0.11	$ 0.01
Marshall County R.E.M.C.	$ 0.08	$ 0.07	$ 0.22	$ 0.08
Northeastern R.E.M.C.	$ 0.07	$ 0.06	$ 0.17	$ 0.06

RETAIL MARKET SHARE

Utility	Residential	Commercial & Industrial	Other
Harrison County R.E.M.C.	68.17%	29.61%	2.22%
Jackson County R.E.M.C.	83.88%	14.34%	1.78%
Marshall County R.E.M.C.	81.77%	15.93%	2.30%
Northeastern R.E.M.C.	62.10%	37.39%	0.51%

Municipal Electric Utilities – 2000 Data

MWH

Utility	Residential	Commercial & Industrial	Other	Total
Anderson Municipal Light & Power	304,886	402,784	4,499	712,169
Auburn Municipal Electric	53,774	485,050		538,824
Bargersville Municipal Power & Light	NA	NA	NA	
Boonville Municipal Light & Power	20,276	14,728	785	35,789
Centerville Municipal Power & Light	13,556	7,229	1,068	21,853
Columbia City Municipal Electric	32,264	77,148	1,091	110,503
Crawfordsville Municipal Electric Light & Power	73,117	316,208	1,461	390,786
Edinburgh Municipal Electric	21,548	71,880	1,092	94,520
Frankfort City Light & Power	70,735	260,238	1,813	332,786
Frankton Municipal Electric	14,733			14,733
Garrett Municipal Electric	5,832			5,832
Greenfield Municipal Electric	56,370	185,690		242,060
Kingsford Heights Municipal Electric	5,536			5,536
Knightstown Municipal Electric	12,443	9,142	715	22,300
Lawrenceburg Municipal Electric	25,591	79,055	1,081	105,727
Lebanon Municipal Electric	58,601	119,264	1,753	179,618
Logansport Municipal Electric	94,174	287,486	2,664	384,324
Mishawaka Municipal Electric	165,704	370,731	5,021	541,456
Paoli Municipal Electric	NA	NA	NA	
Peru Municipal Electric Light & Power	NA	NA	NA	
Richmond Municipal Power & Light	193,681	742,307	8,232	944,220
South Whitley Municipal Electric	NA	NA	NA	
Straughn Municipal Electric	1,357			1,357
Tipton Municipal Electric	33,700	72,164	868	106,732
Troy Municipal Electric	9,576			9,576
Washington City Municipal Light & Power	64,755	89,766	3,444	157,965
Totals	**1,332,209**	**3,590,870**	**35,587**	**4,958,666**

REVENUE (000s)

Utility	Residential	Commercial & Industrial	Other	Total
Anderson Municipal Light & Power	$ 19,047	$ 20,650	$ 544	$ 40,241
Auburn Municipal Electric	2,436	20,838	224	23,498
Bargersville Municipal Power & Light	NA	NA	NA	
Boonville Municipal Light & Power	1,390	1,443	599	3,432
Centerville Municipal Power & Light	648	410	79	1,137
Columbia City Municipal Electric	2,112	4,377	216	6,705
Crawfordsville Municipal Electric Light & Power	4,767	14,558	2,251	21,576
Edinburgh Municipal Electric	1,235	3,713	73	5,021
Frankfort City Light & Power	4,190	10,649	217	15,056
Frankton Municipal Electric	910			910
Garrett Municipal Electric	3,829			3,829
Greenfield Municipal Electric	3,278	8,097	605	11,980
Kingsford Heights Municipal Electric	244	96	318	658
Knightstown Municipal Electric	693	513	39	1,245
Lawrenceburg Municipal Electric	1,434	3,697	110	5,241
Lebanon Municipal Electric	3,555	6,140	186	9,881
Logansport Municipal Electric	6,105	14,407	312	20,824
Mishawaka Municipal Electric	7,041	20,731	5,692	33,464
Paoli Municipal Electric	NA	NA	NA	
Peru Municipal Electric Light & Power	NA	NA	NA	
Richmond Municipal Power & Light	11,134	30,602	19,395	61,131
South Whitley Municipal Electric	NA	NA	NA	
Straughn Municipal Electric	73	6	6	85
Tipton Municipal Electric	1,908	3,544	96	5,548
Troy Municipal Electric	215	361	25	601
Washington City Municipal Light & Power	3,773	4,261	594	8,628
Totals	**$ 80,017**	**$ 169,093**	**$ 31,581**	**$ 280,691**

AVERAGE PER KWH

Utility	Residential	Commercial & Industrial	Other	Total
Anderson Municipal Light & Power	$0.06	$0.05	$0.12	$0.06
Auburn Municipal Electric	$0.05	$0.04	-	$0.04
Bargersville Municipal Power & Light	NA	NA	NA	
Boonville Municipal Light & Power	$0.07	$0.10	-	$0.10
Centerville Municipal Power & Light	$0.05	$0.06	$0.07	$0.05
Columbia City Municipal Electric	$0.07	$0.06		$0.06
Crawfordsville Municipal Electric Light & Power	$0.07	$0.05		$0.06
Edinburgh Municipal Electric	$0.06	$0.05	-	$0.05
Frankfort City Light & Power	$0.06	$0.04	$0.12	$0.05
Frankton Municipal Electric	$0.06	-	-	$0.06
Garrett Municipal Electric	$0.66			$0.66
Greenfield Municipal Electric	$0.06	$0.04		$0.05
Kingsford Heights Municipal Electric	$0.04	-	-	$0.12
Knightstown Municipal Electric	$0.06	$0.06	$0.05	$0.06
Lawrenceburg Municipal Electric	$0.06	$0.05	$0.10	$0.05
Lebanon Municipal Electric	$0.06	$0.05	$0.11	$0.06
Logansport Municipal Electric	$0.06	$0.05	$0.12	$0.05
Mishawaka Municipal Electric	$0.04	$0.06		$0.06
Paoli Municipal Electric	NA	NA	NA	NA
Peru Municipal Electric Light & Power	NA	NA	NA	NA
Richmond Municipal Power & Light	$0.06	$0.04		$0.06
South Whitley Municipal Electric	NA	NA	NA	NA
Straughn Municipal Electric	$0.05	-	-	$0.06
Tipton Municipal Electric	$0.06	$0.05	$0.11	$0.05
Troy Municipal Electric	$0.02	-	-	-
Washington City Municipal Light & Power	$0.06	$0.05	$0.17	$0.05

RETAIL MARKET SHARE

Utility	Residential	Commercial & Industrial	Other
Anderson Municipal Light & Power	47.33%	51.32%	1.35%
Auburn Municipal Electric	10.37%	88.68%	0.95%
Bargersville Municipal Power & Light	NA	NA	NA
Boonville Municipal Light & Power	40.50%	42.05%	17.45%
Centerville Municipal Power & Light	56.99%	36.06%	6.95%
Columbia City Municipal Electric	31.50%	65.28%	3.22%
Crawfordsville Municipal Electric Light & Power	22.09%	67.47%	10.43%
Edinburgh Municipal Electric	24.60%	73.95%	1.45%
Frankfort City Light & Power	27.83%	70.73%	1.44%
Frankton Municipal Electric	100.00%	0.00%	0.00%
Garrett Municipal Electric	NA	NA	NA
Greenfield Municipal Electric	27.36%	67.59%	5.05%
Kingsford Heights Municipal Electric	37.08%	14.59%	48.33%
Knightstown Municipal Electric	55.66%	41.20%	3.13%
Lawrenceburg Municipal Electric	27.36%	70.54%	2.10%
Lebanon Municipal Electric	35.98%	62.14%	1.88%
Logansport Municipal Electric	29.32%	69.18%	1.50%
Mishawaka Municipal Electric	21.04%	61.95%	17.01%
Paoli Municipal Electric	NA	NA	NA
Peru Municipal Electric Light & Power	NA	NA	NA
Richmond Municipal Power & Light	18.21%	50.06%	31.73%
South Whitley Municipal Electric	NA	NA	NA
Straughn Municipal Electric	85.88%	7.06%	7.06%
Tipton Municipal Electric	34.39%	63.88%	1.73%
Troy Municipal Electric	35.77%	60.07%	4.16%
Washington City Municipal Light & Power	43.73%	49.39%	6.88%

APPENDIX B: MISO and Alliance Member Companies

MISO Companies

Transmission Owning Members

- Alliant Energy
- American Transmission Company LLC
- Central Illinois Light Co.
- Cinergy Services, Inc.
- Hoosier Energy R.E.C.
- Indianapolis Power & Light
- LG&E Energy Companies
- Northwestern Wisconsin Electric
- Otter Tail Power Co.
- Southern Illinois Power Cooperative
- Southern Indiana Gas and Electric Company
- Wabash Valley Power Association, Inc.
- Xcel Energy (formerly Northern States Power)

Non-Transmission Owning Members

- Air Products and Chemicals, Inc.
- American Electric Power Co.
- American Municipal Power - Ohio, Inc.
- Automated Power Exchange, Inc.
- Calpine Power Services Co.
- Cargill-Alliant, LLC
- Cleveland Public Power, Dept. of Public Utilities
- Connectiv Energy Supply, Inc.
- Constellation Power Source, Inc.
- Consumers Energy Company
- Detroit Edison Company
- Duke Energy North America, LLC
- Dynegy, Inc.
- Edison Mission Marketing & Trading, Inc.
- Enron Power Marketing, Inc.
- Exelon Generation Co. LLC
- FirstEnergy Corp.
- Granite City Steel Division, National Steel Corp
- Illinois Municipal Electric Agency
- Indeck-Rockford, LLC
- Madison Gas and Electric
- Mirant Americas Energy Marketing, LP
- Missouri River Energy Services
- PG&E Generating Co.
- Reliant Energy Inc.
- Tenaska Power Services Co.
- Williams Energy Marketing & Trading Co.
- Wisconsin Electric Power Company
- Wisconsin Public Power, Inc.
- WPS Resources Corporation

Membership Pending

- City Water, Light & Power
- Indiana Municipal Power Association
- Lincoln Electric Power System
- Manitoba Hydro
- Minnesota Power
- Sunflower Electric Power Corp.
- Utilicorp United

Alliance RTO Companies

- Ameren Corporation
- Dominion
- American Electric Power Service Corporation
- FirstEnergy Corporation
- Commonwealth Edison Company
- Illinois Power Company
- Consumers Energy Company
- Northern Indiana Public Service Company Inc.
- Dayton Power and Light Company
- The Detroit Edison Company

Chapter 9 List of Acronyms

ARP Alternative Regulatory Plan
ARTO Alliance Regional Transmission Organization
CAC Citizens Action Coalition
CPU California Public Utility Commission
DOE Department of Energy
DSM Demand-Side Management
ECAR East Central Area Reliability Council
FAC Fuel Adjustment Cost Charge
FERC Federal Energy Regulatory Commission
G&T Generation and Transmission
HE Hoosier Energy
I&M Indiana Michigan Power Company, subsidiary of AEP
ICC Illinois Commerce Commission
IMPA Indiana Municipal Power Agency
IOU Investor-owned Utility
IPL Indianapolis Power and Light
IRP Integrated Resource Plan
ISO Independent System Operator
IURC Indiana Utility Regulatory Commission
kWh Kilowatt Hour
MISO Midwest Independent System Operator
NAERO North American Electric Reliability Organization
NERC North American Electric Reliability Council
NIPSCO Northern Indiana Public Service Company
OUCC Office of Utility Consumer Counselor
PUCO Public Utility Commission of Ohio
PSI PSI Energy
PUHCA Public Utility Holding Company Act 1935
PURPA Public Utility Regulatory Policies Act 1978
REMC Rural Electric Membership Cooperative
RTO Regional Transmission Organization
SEC Securities and Exchange Commission
SIGECO Southern Indiana Gas & Electric Company
T&D Transmission and Distribution
WVPA Wabash Valley Power Association